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Meeting Asian LNG Demand

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Cover: An LNG tanker passes boats along the coast of Singapore February 3, 2017. Picture taken February 3, 2017. REUTERS/Gloystein Henning

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INTRODUCTION

Although liquefied natural gas (LNG) currently makes up only 10.47 percent of the total global demand for natural gas,[1] it has become a vital source of energy for most Asian countries and demand is increasing by leaps and bounds. Fortunately, this demand is balanced by the plentiful supplies from the Middle East, complemented increasingly by Australian and United States production shipped to Asia, making LNG a major trans-Pacific trade.

Consumers are switching to LNG for a variety of reasons. Environmental factors have driven consumers to look to natural gas as a transitional source of energy, moving away from coal and crude oil in favor of cleaner fuels where zero-carbon energy is either cost prohibitive or unable to be deployed at sufficient scale and speed. However, some of the largest users cannot rely on piped natural gas because the distance to producers is too large or geographically too difficult. Some users would be close enough for piped gas but are unable to overcome the political problems imposed by neighbors.

LNG, which can be shipped anywhere in the world, offers the ability to use natural gas regardless of geographical limitations or political pressures. For example, Kuwait, located next to the largest gas fields in the world, imports LNG to bypass Saudi Arabia's veto on Qatari pipelines crossing its territory. Similarly, the flow of Qatari LNG to India cannot be physically blocked by Pakistan. China can diversify its supplies by shipping in large volumes of gas from numerous producers, no matter the distance: China can import piped gas from Turkmenistan or Myanmar, and buy LNG from Qatar, Australia, and the United States.

By the same token, existing and potential suppliers of LNG are keenly aware of the large demand and are investing heavily in new production facilities, often called "trains," to meet the increase in demand. The growth of the global supply of LNG has been quasi-exponential, going from 50 million tons per year (t/y) in 1980[2] to 369 million t/y in 2017.[3] There were even warnings by analysts in 2016-2017 that LNG supplies were increasing so quickly that prices could fall rapidly, rendering liquefaction facilities unprofitable and ultimately bringing about a major decline in production. However, increases in production have been balanced by an unexpected rapid increase in Asian demand led by China, new demand from Korea, and the emergence of India as a major market.

CIF VS. FOB PRICING MECHANISM, AND THE NATURE OF LNG

Unlike crude oil, the price of LNG is quoted including transport and insurance costs (referred to as CIF). Sellers of LNG bear the entire shipping costs, unlike the producers of crude oil who sell free on board (FOB), leaving the cost of shipping including loading, brokerage, insurance, etc., to the buyers. The LNG buyer looking at a price quote does not need to be concerned with the location of the production, be it Qatari gas, or LNG from the Gulf of Mexico or the Yamal Peninsula in Russia. Chinese buyers will only consider the quoted price landed in Shanghai, for example. The sellers, meanwhile, compete on that landed price expectation, so that the seller's net income, also called the netback income, is the landed price minus all transport expenses. Gas landed in China at $10.58 in October 2018 will net back approximately $8 to Australian producers, $6.50 to Qatari ones, or $5 to American ones, who then must decide whether they accept the returns on capital implied by their netback values.

The nature of LNG also allows for a diverse source of buyers. Whereas crude oil is always ultimately bought by refineries, LNG can be bought by any consumer who can use the product without further processing, beside regasification. Buyers can include electricity companies, gas companies, and industrial users.

1 Computed from *BP Statistical Review of World Energy*, BP, June 2018.

2 "Global Natural Gas Markets Overview," US Energy Information Agency, August 2014, Table 5, https://www.eia.gov/workingpapers/pdf/global_gas.pdf.

3 *2018 World LNG Report*, International Gas Union, 2018, 5.

For the past twenty years, the main producer has been Qatar, which has the largest gas field in the world. Qatar today is under some competitive pressure from newcomers like Australia and the United States. The American producers are now coming rapidly to the market with large volumes, which may not reach the Australian or Qatari levels but are large enough to seriously compete in Asia.

There has been concern in the past few months that demand is increasing so quickly that supply may not meet it in the 2020s.[4] Of course, the reverse fear existed a year earlier when the specialized press was equally worried that quickly increasing supply would glut the market. Such gyration in estimates and subsequent fears in this relatively new industry are to be expected. By and large, however, it seems that both buyers and producers see that demand and supply will remain in balance. Indeed, should demand continue to expand, it will be met by a portion of the numerous projects being mulled to increase production more than two-fold to 875 million (t/y).[5]

Regional politics can impact LNG development, sometimes negatively. For instance, Iran, which has the largest gas reserves in the world, cannot build its LNG industry due to sanctions from Western countries, which in part has allowed the new Australian and United States producers to establish market share, even though their gas reserves are much smaller than Iran's.

LNG is a flexible commodity. It is relatively easy to transport, albeit at a cost. It is fungible, i.e., buyers can use gas from any LNG source at minimum inconvenience. Thus, new US production from the Gulf of Mexico or LNG from the Yamal peninsula in Russia can displace Qatari gas in Europe, which then finds a home in East Asia. This implies that all new sources and all new buyers influence the demand and supply channels.

Because the growth of the LNG market is most prominent in Asia, this paper focuses on the commerce of LNG as mainly a trans-Asian (and Australian) affair. It reviews the demand growth in China and India, as well as the continued large demand from Japan and Korea, and how they are currently supplied by Qatar and Australia. Qatar's role as the current dominant LNG supplier is examined in detail, in particular its influence over various elements of the global market and how it is responding to the prospect of a more competitive LNG market in coming years. As a complement to the focus on the Middle East, this paper also examines new important suppliers to Asia, like the United States, and future important ones like Russia and Mozambique.

UNITS OF MEASUREMENT AND PRICING

Most reports present LNG facts in cubic meters, cubic feet, standard cubic feet, tons of LNG, and/or MMBtu, while prices usually are quoted in US dollars per MMBtu.

The translation from one unit to the other can be confusing and is somewhat misleading as the actual amounts of volume, weight, and prices are influenced by the mix of gas being liquified, the main gas methane being associated in small quantities with more or less ethane, butane, propane, or heavier molecules.

A simple rule of thumb translation is offered here, knowing that it is only a rough estimate of the exact figures for any given production. According to a table offered by International Gas Union: 1 ton of LNG provides 53.4 MMBtu and 1 cubic meter (m^3) of LNG corresponds to 24 MMBtu. For example:

1. A standard LNG tanker that can load 180,000 m^3 of LNG will hold about 4.3 million MMBtu. Pricing is usually provided in dollars per MMBtu. Thus, a shipment to China landed at $10/MMBtu would amount to $43 million.

2. Net back gross income for a country like Qatar, with production of 80 million t/y, would amount to 4,272 million MMBtu. If the netback to Qatar (i.e., gross income minus transport and cost of production) is estimated around $6/MMBtu, the netback income of Qatar would be about $25.6 billion.

4 "Shell Warns of Liquefied Natural Gas Shortage as LNG Demand Blows Past Expectations," *CNBC*, February 26, 2018, https://www.cnbc.com/2018/02/26/shell-warns-of-lng-shortage-as-demand-for-liquefied-natural-gas-booms.html.

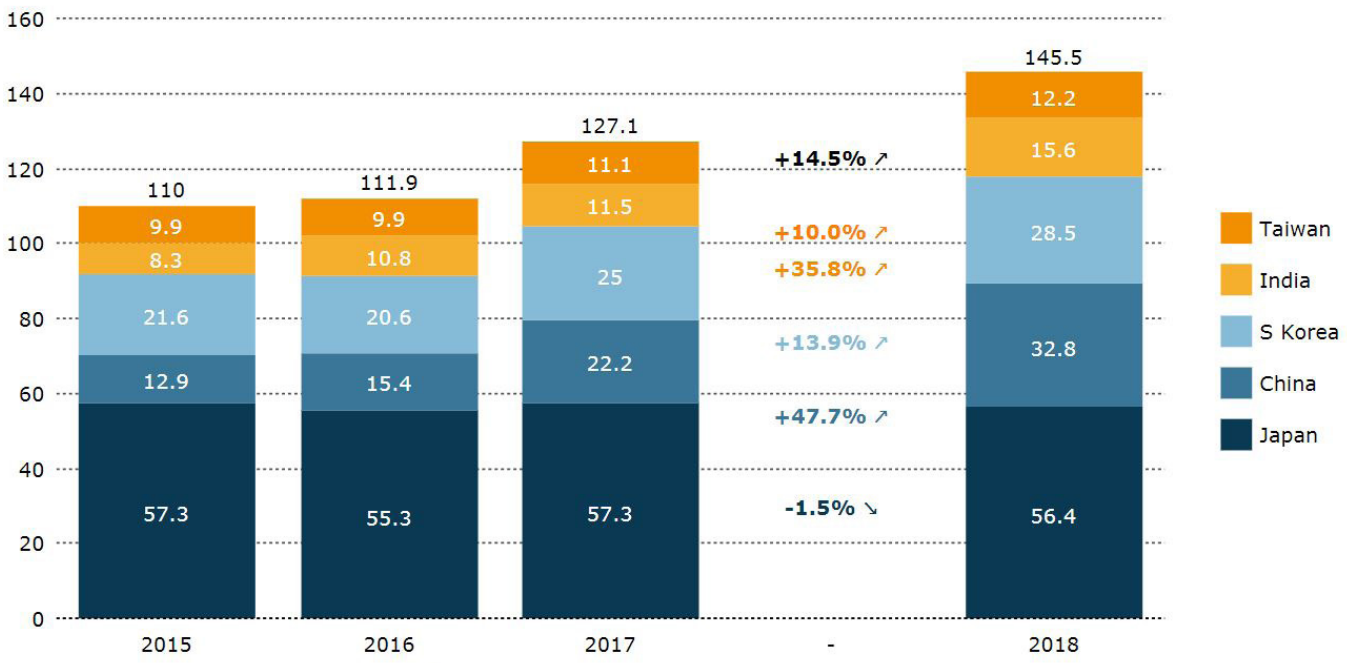
5 *2018 World LNG Report*, International Gas Union.

OVERVIEW OF ASIAN DEMAND

The five economic giants of Asia—Japan, China, Korea, Taiwan, and India—are the main markets for LNG. Together these economies account for 70 percent of global LNG demand, with imports totaling 127.1 million tons in 2017 and expected to reach 145.5 million tons in 2018. LNG is offering the Asian economies rapid access to new sources of energy. While both India and China have their own substantial gas reserves, their ability to increase local production cannot match the increase in demand. LNG import facilities are relatively easy to set up near the main demand centers. Utility companies in those two countries can switch to gas without major changes in infrastructure, albeit at some expense. Local buyers of LNG can supply industries and households by tapping their regasified product into the local distribution networks. Hence, as the countries require a major effort to decrease pollution in large cities, LNG imports provide a quick, safe solution.

Along with the post-2014 decline in oil prices, prices for LNG in East Asia declined substantially but rebounded somewhat in 2018. The cost, insurance, and freight (CIF) price had fallen as low as $4 in 2016 after highs of over $16/MMBtu in 2014. These prices have now been hovering around $10/MMBtu despite market expectation of price declines due to numerous new LNG trains coming online. This relatively stable price level underscores the balancing of supply and demand due to massive growth of imports by China, Korea, and India in 2017 and 2018, with expectations that these demand increases will continue and be matched by supplies from the United States and Russia.

Figure 1: LNG Demand in Asia, in millions of tons per annum

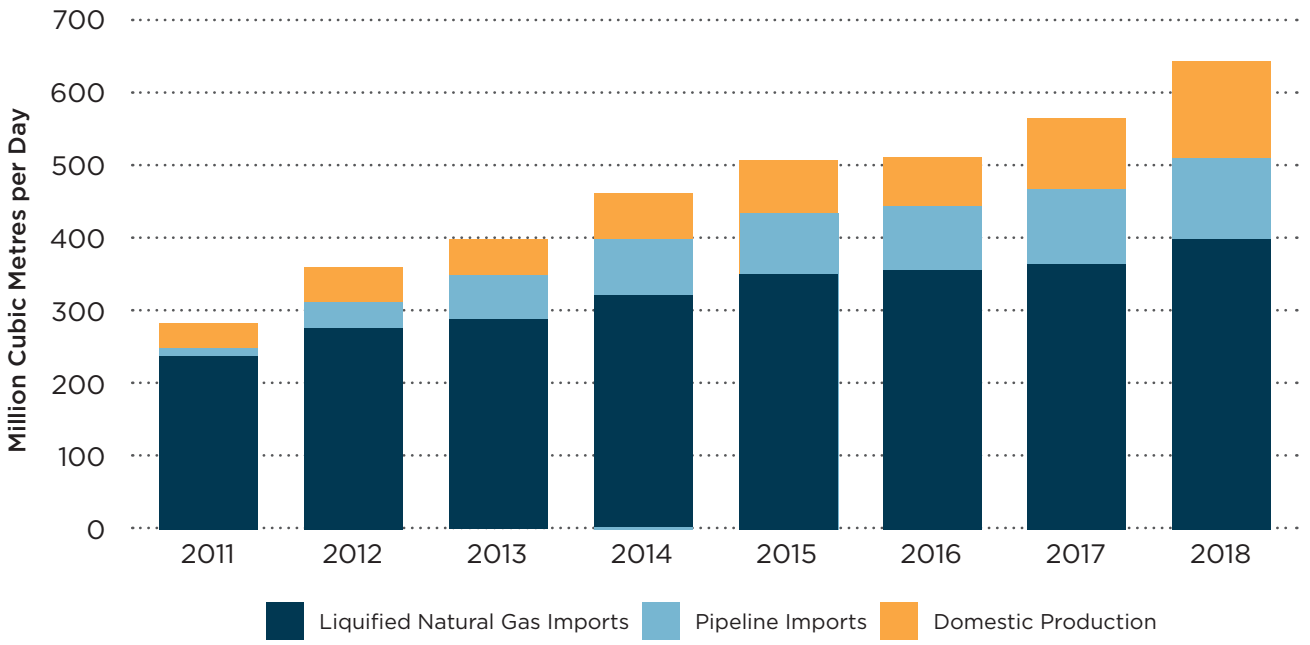


*2018 ESTIMATE FOR INDIA AND TAIWAN BASED ON JAN-JULY. ^THESE KEY ASIAN IMPORTERS ARE ALSO BY FAR THE LARGEST GLOBAL IMPORTERS ACCOUNTING FOR 68% OF GLOBAL LNG TRADE IN 2017.

Source: *Middle East Economic Survey*, September 28, 2018.

6 *BP Statistical Review of World Energy*, BP, June 2018.

Figure 2: China Natural Gas Supply by Source, 2010-2017



Source: Chart based on data from the Energy Information Administration's "Today in Energy," February 23, 2018.

CHINA

China has sizable domestic gas reserves of 15.5 trillion m^3 (92 tcf) and produces 149.2 billion m^3 of gas annually. China's gas consumption was 243.6 billion m^3 in 2017, up from 73.7 billion m^3 in 2010.[6] This spike in consumption helps to explain China's rapid increase in gas imports.

Given this increase in gas consumption and relative reliance on imports, China appears to be diversifying its gas supplies to avoid dependence on just one or two sources of natural gas, just as it is with imports of crude oil. China imports gas via two main pipelines: one from Turkmenistan supplied 31.7 billion m^3 in 2017 to the Chinese national pipeline grid, and one from Myanmar to Kunming in Southern China supplied 3.3 billion m^3 in 2017.[7]

China has plans to build more pipelines. The main project is the 2,800-kilometer Altai pipeline that is expected to carry 30 billion m^3 from the Siberian gas fields to Xinjiang for linkage to the Chinese grid. Even though agreements have been signed by Russian and Chinese officials in 2006, the pipeline has not yet been built.

In addition to receiving gas imports via pipeline, China imports enough LNG to be the second largest importer in the world after Japan, having overtaken Korea for the number two spot in 2017. However, in contrast to Japanese imports, which are stable, Chinese imports are rapidly increasing. China's LNG imports increased by 50.7 percent[8] in 2017 and about 25 percent for the first eight months of 2018, at which point it had already imported 32.9 million tons of LNG.[9] The increase has been driven in part by a preliminary shift away from coal, with efforts underway to reform the Chinese energy sector and usage, and decrease pollution in large cities by replacing coal power generation with natural gas. As a result, Chinese LNG imports went from 3 million t/y in 2007 to 39.5 million in 2017[10] and are projected to increase to 55 million t/y by 2020.[11] Whether this trajectory will be realized is an open question, however, given the countervailing effect of continued subsidies for coal production and usage, as well as the temporary rever-

7 *BP Statistical Review of World Energy*, BP, June 2018.
8 Computed from the *2017* and *2018 World LNG Reports*, International Gas Union, Table 3.7.
9 "China LNG Seen Up 25 percent," *Reuters*, September 6, 2018.
10 Middle East Economic Digest, September 28, 2018.
11 Institute for Energy Economics, Japan, estimates, per IEEJ presentation to the Atlantic Council, November 16, 2018.

Liquefied natural gas (LNG) storage tanks and a membrane-type tanker are seen at Tokyo Electric Power Co.'s Futtsu Thermal Power Station in Futtsu, east of Tokyo, February 20, 2013. Japan's imports of LNG hit a monthly record of 8.23 million tons in January, on an increased need for fuel to generate electricity after the nuclear sector was hit by the Fukushima crisis, customs-cleared Ministry of Finance data showed. REUTERS/Issei Kato

sion back to coal over part of 2018 in the face of electricity shortages due to strong industrial power demand. China's commitment to power sector fuel-switching will likely be tested further at various points in the coming years, and will play a large part in determining the shape of Chinese LNG demand over this period.

China initially imported most of its LNG from Qatar, which provided 37 percent of all imports in 2013. Since then, Qatar's market share of the Chinese market has declined substantially to about 19 percent in 2016 and 20.7 percent in 2017, when it trailed behind Australia's 45 percent share.[12]

JAPAN

Japan has no domestic natural gas production and no pipeline links to the Asian continent, forcing the country to rely solely on LNG for its gas needs. Japan has always been the world's largest importer of LNG. In the wake of the 2011 Fukushima nuclear disaster and subsequent shutdown of the country's nuclear plants, which had provided 30 percent of its electricity production, Japan's LNG imports increased further. As reactors have started to come back online in recent years, Japan's LNG imports have stabilized in the range of 55.3 million t/y and 57.3 million t/y and are expected to be 56.4 million t/y in 2018.[13]

Japan has a diversified portfolio of LNG sources, buying from Australia (25.67m/t), Malaysia (14.81m/t), Qatar (10.13 m/t), Russia (7.26 m/t), and others including Indonesia, Abu Dhabi, and the United States, with shipments from Cove Point, Maryland, and Sabine Pass on the Gulf of Mexico.[14]

12 Computed from *2018 World LNG Report*, International Gas Union, Table 3.2, 14.

13 Middle East Economic Survey, 61, no. 39, September 28, 2018.

14 GIIGNL (International Group of LNG Importers), *Annual Report*, 2018, 21.

SOUTH KOREA

Like Japan, South Korea also lacks gas pipelines to bring imports from nearby suppliers. Given the lack of pipeline options, South Korea imported 37.83 million tons of LNG in 2017,[15] up from 32.6 million tons in 2010, and was the second largest LNG importer in the world until China overtook it in 2017. Unlike Japan, South Korea has one producing gas field, the Donghae-1 field located offshore in the Ulleung basin. The field produces between 0.1 and 0.2 billion cubic meters (bcm) annually but is expected to be depleted by 2020.

South Korea's LNG imports increased dramatically in 2013 due to a scandal over falsified safety tests of nuclear power-plant equipment, which led to the closure of over half of South Korea's nuclear power plants. To compensate for the reduction in nuclear energy output, power companies relied on increased imports of LNG and coal. Since 2013, many of the nuclear power plants have restarted, placing downward pressure on LNG imports. However, President Moon's administration has pledged to reduce pollution by closing the dirtiest coal-fired power plants and has expressed a desire to move toward nuclear-free power production. Given these trends, LNG imports are expected to increase.

INDIA

India's gas-demand trajectory could impact global markets, as it looks to boost its capacity to import and distribute larger amounts of LNG. This is a strategic shift for the country, which due to the geography of the subcontinent, is inhibited from importing natural gas by pipeline because it would need to pass through Pakistan, a political impossibility at this time. Thus, LNG accounts for all of India's gas imports, and its three largest suppliers are Qatar (10.13 million tons in 2017), Nigeria (3.08 million tons in 2017), and Australia (1.71 million tons in 2017). While the country was the fourth-largest natural gas importer globally in 2017, it also boasts sizable domestic gas production, approximately 31 bcm annually. However, domestic production is insufficient to meet rapidly growing demand now and in the future. In 2017, natural gas consumption in India was 55.6 bcm, up from 35.5 bcm in 2005.[16] This consumption is expected to expand greatly in the coming years due to increased demand for electricity from less-polluting sources than coal and the increased utilization of natural gas for transportation and cooking.

Gas is an important part of the political and policy discussion in India. India's capacity to import LNG is currently limited by the low number of receiving terminals and the limited connections from them to downstream consumers. The Modi administration plans to increase natural gas as a share of the nation's energy consumption from the current 7 percent to 15 percent by 2022. In pursuit of this goal, the government announced an infrastructure plan to expand the number of LNG import terminals from four in 2016 to 10 at an unspecified date.[17]

15 GIIGNL (International Group of LNG Importers), *Annual Report*, 2018, 21.

16 Jean-Francois Seznec and Ramesh Pallakonda, *India's Energy Needs and the Arab Persian Gulf*, Atlantic Council, January 2017.

17 Wim de Vriend, "Something Has to Give in the LNG Market," *OilPrice.com*, April 20, 2016.

THE TRADITIONAL SUPPLIERS TO ASIA

QATAR

While once the undisputed leader in LNG exports, Qatar lost substantial market share in Asia once Australia entered the LNG market. Qatar's declining market share, especially in China, is caused by three coinciding factors:

- Australia introduced large volumes to the East Asian market at very competitive CIF prices due to the country's proximity to those markets;
- LNG supplies from the United States and Russia entered Asian markets; and
- Japan, the largest LNG importer, did not increase imports over the past four years, and thus did not contribute to demand growth in an increasingly well-supplied market.

Figure 3: Qatar's Market Share in China

Year	Chinese LNG imports in million t/y	Qatar's share in million t/y	Percent
2013	18.8	7.0	37.0
2014	19.8	6.7	33.8
2015	19.7	4.8	24.36
2016	26.2	5.0	19.0
2017	39.5	8.19	20.7

Source: *2018 World LNG Report*, International Gas Union

Qatar's loss of LNG market share came at a time of lower oil prices in 2014 and caused the country's gross income to fall from $73.4 billion in 2013 to less than $23.7 billion in 2016. Fortunately for Qatar, some of the decline was mitigated by the country's ability to increase production past its nameplate capacity of 77 million tons per year (t/y) and ultimately export over 80.9 million t/y in 2017. Qatar has continued to replace some of its declining market share in East Asia by becoming the largest supplier to India, which is rapidly becoming one of Qatar's main customers with imports of over 10.6 million t/y in 2016.[18] Oil prices, used as an index to compute LNG prices in most long-term contracts, have also increased significantly, improving Qatar's cash flow.

Qatar wants to remain the world's leading LNG producer and compete aggressively in the Asian market. It is aware of the competition from Australia and concerned by potential capacity increases from the United States, Russia, and new East African producers. Therefore, Qatar is planning to increase its natural gas production and LNG facilities to about 110 million t/y in its bid for market share and staying power as the largest producer. To meet these goals, Qatar canceled its ten-year moratorium on new production in the North Dome and is actively seeking to build another 23 million t/y of LNG capacity, though the new output will not hit the markets until 2024. The moratorium gave Qatar a chance to assess the impact of the massive draw on the natural gas reserves caused by the LNG production, the growth of petrochemical industries, the large increases in electricity generation, and the demand for desalinated water. At the time the moratorium was imposed, Qatar claimed about 400 years of production reserves, but the state did not want to push its reserves too hard, knowing that with numerous industrial and gas-based projects on hand could increase the depletion rate enough to cut this time frame to 140 years.[19] The lifting of this moratorium suggests that Qatar's current need for LNG market share is making the country modify its cautious posture of ten years ago.

Qatar also has decided to join forces with one of its commercial competitors, taking a major stake in the 17 million t/y LNG Golden Pass project in the United States in a joint venture with Exxon Mobil Corp. It is not clear whether the project, scheduled for a 2021-2022 completion, will come to fruition, as no FDI has been announced. However, Qatar recently announced that it would invest $20 billion in US energy projects.[20]

18 "India LNG Imports," *Middle East Economic Survey*, 61, no. 46 (2018), 48.

19 Computed from the figures published by BP on reserves and usage for natural gas in *BP Statistical Review of World Energy*, June 2018, 26 and 28.

20 *Reuters*, December 16, 2018. Qatar Petroleum to invest $20 billion in US in major expansion

IMPACT OF THE TENSIONS BETWEEN QATAR AND SAUDI ARABIA AND UAE

The ongoing embargo imposed by Saudi Arabia and the UAE on Qatar in 2017 has not impacted Qatar's LNG exports. Shipping energy products cannot be blocked by Qatar's neighbors as it would be seen as a violation of international law and the rights of free passage on the seas. The embargo has mostly succeeded in increasing the cost of most imports into Qatar, a country that imports almost everything it consumes.

Ultimately, the embargo has had more of a political than an economic impact in the sense that it has shattered the unity of the Gulf Cooperation Council (GCC). It has also been a major strategic boon for Iran and Turkey, which are more than pleased to replace Saudi Arabia and the UAE as allies to Qatar. The embargo also has put the United States in an awkward position as it seeks to navigate its position between very close allies.

In mid-2017, it appeared that the political crisis between Qatar and its neighbors would be short lived. Qatar's income was decreasing rapidly due the decline in world prices for oil and gas, which was eating into its financial reserves, thus putting the country under pressure to accommodate the Saudi and UAE demands. However, as oil prices have increased in 2017 and 2018, Qatar's income has increased to over $80 billion. Qatar currently produces 600,000 barrels/day of crude, 700,00 b/d of natural gas liquids (NGLs include liquid petroleum gases and condensates), and now over 80 million t/y of LNG.

While Qatar remains a long way from earning what it did in 2013, the country is under far less pressure than it was in 2016, even if the picture is not entirely rosy. To maintain its image in the world, Qatar is spending heavily to develop its infrastructure to host the World Cup in 2022. While Qatar is rumored to have $350 billion in its sovereign wealth fund (SWF), Qatar Investment Authority (QIA) is the most opaque of the Gulf SWFs and does not provide any figures on its total assets or income.[1] Despite the blockade, Qatar continues to make investments in the US and Asia and successfully tapped the international debt markets for $12 billion last spring. However, it has tightened liquidity and is overbanked, making its financial position less than comfortable, although it seems Qatar is weathering the blockade better than some expected. Nonetheless, Saudi Arabia and the UAE believe that Qatar will not be able to sustain its independent streak for long. Thus, the Saudis and the Emiratis can feel that they do not need to negotiate but need to wait for a possible, and in their view likely, financial collapse of Qatar. On the LNG front, this means that Qatar is under more pressure than it has been in the past to sell its gas at competitive prices, which may give buyers a chance to cut better deals for themselves.

Like Kuwait and Bahrain, Saudi Arabia and the UAE are short of natural gas needed to run their extensive industrial base as well as huge water desalination and electricity generation plants. Saudi Arabia does have sizable domestic dry gas potential, but this gas is very rich in hydrogen sulfide, which requires extensive and expensive treatment to be used. Saudi Arabia could pay Qatar above its present LNG net back price, transfer gas by short pipelines, and still be able to buy Qatari gas at a lower price than the cost of Saudi domestic production. Such sales would also limit the need for Qatar to spend $24 billion[2] to increase its LNG capacity to 110 million t/y.

Unfortunately, even though an integrated GCC piped gas market would benefit all participants and could perhaps help reduce tensions, this topic is off the table in the present political climate

1 Seznec Jean-Francois and Mosis Samer, *The Financial Markets of the Arab Gulf* (New York/London: Routlege, 2018), 121-122.

2 "Qatar Enlarges LNG Expansion," *Middle East Economic Survey*, September 18, 2018.

It is noteworthy to see Qatar seized the challenge of remaining a major producer, even if not all of the production will be from North Dome.

Export options for Qatari gas are limited to LNG in great part because its main consumers are too far to be serviced by pipelines. However, exports are also limited by regional political considerations. In 2006, Qatar, Bahrain, and Kuwait were in talks to build a pipeline under water between Qatar and the other two countries to supply them with much-needed natural gas. However, Saudi Arabia vetoed the construction of the pipeline, which would have had to have gone through its territorial waters. Saudi Arabia did not offer any explanation for the veto, but it seemed to have focused on limiting Qatar's potential influence over Kuwait and Bahrain.[21] The Saudi action was a precursor, among others, for the current tensions between Saudi Arabia and Qatar and has stymied any further negotiations for these members of the Gulf Cooperation Council to buy pipeline gas from Qatar.

Since then, Kuwait has been buying LNG from the world market, including from its close neighbor Qatar at the price of between $7/MMBtu and $8/MMBtu,[22] while piped gas would have been somewhere between $2/MMBtu and $6/MMBtu. Bahrain will also start importing LNG in 2019. However, political tensions have not always impeded gas trade or pipeline construction, as shown by the Dolphin pipeline from Qatar to the United Arab Emirates and Oman, which was built despite Saudi opposition.

The market for LNG is quite different from that of crude oil, the prices of which are quoted in barrels FOB, i.e., exclusive of shipping and insurance costs, while LNG contracts are usually denominated in US dollars per MMBtu, covering cost, insurance, and freight to the country of destination. Thus, the CIF pricing greatly impacts suppliers who are mainly dependent on independent shippers for one of the most important costs associated with the sale of LNG. The distances between buyers and sellers are vast, and sudden changes in shipping costs will change the suppliers' ability to compete. Qatar, the largest supplier of LNG in the world, has established a fleet of LNG tankers owned by Nakilat, a state-owned company,[25] which protects it from the vagaries of the tanker market. Nakilat is the largest LNG tanker company in the world, giving Qatar an important competitive advantage in CIF markets, especially to East Asia.

NAKILAT, THE LNG SHIPPING COMPANY OF QATAR

Nakilat owns or has stakes in sixty-nine LNG vessels: twenty-five are fully owned, forty partially owned, and Nakilat owns 50 percent of four LPG carriers. Nakilat directly manages and operates eight Q-Flex (capacity of 217,000 m^3), six Q-Max (capacity of 266,000 m^3) and the four LPG vessels. The company ships its LNG on fourteen Q-Max, 31 Q-Flex, and twenty conventional carriers (145,000 to 170,000 m^3). The LNG vessels have a total capacity of 9 million m^3, 12 percent of the world capacity for an investment of about $11 billion. Nakilat also owns one floating storage regasification unit (FSRU), operates a ship-repair yard, various servicing equipment and vessels,[26] and manages eighteen of the carriers directly through National Qatar Shipping Ltd (NQSL). The rest of the carriers are operated in joint ventures with large shipping operators.

INDONESIA

Indonesia is a large supplier of LNG, mostly to Asia. In 2017, Indonesia exported 18.71 million tons of LNG, mostly to China (3.1 million t/y), Japan (6.51 million t/y), and South Korea (3.71 million t/y).[27] Most of Indonesia's LNG comes from a facility in Bontang that is wholly owned by the Indonesian government, while two trains with a capacity of 7.6 m/t are owned by BP PLC, China National Offshore Oil Corp. (CNOOC), JXTG Nippon Holdings Inc., Mitsubishi Corp., and

21 "Attiyah Cautious on Committing Gas to Bahrain as Reserves Studies Continue," *Middle East Economic Survey* 49, no. 15, (2006).

22 Figure provided by a participant at the Arab Gulf States Institute in Washington conference on energy, October 18, 2018.

25 The state of Qatar owns 51 percent of Nakilat, including Qatar Petroleum, which controls all the Qatari LNG marketing. The Qatari public owns the remainder, with its stock trading on the stock exchange in Doha.

26 "Vessel Support Unit," Nakilat website, accessed April 25, 2017, http://www.nakilat.com.qa/Page/Vessel.

27 *GIIGNL Annual Report*, 2018.

other companies. While Indonesia's LNG production has declined slightly since 2014, due to declining feedstock from its gas fields, it is nevertheless building a new LNG export facility with a 4 million t/y capacity.[28]

MALAYSIA

Malaysia is the third-largest supplier of LNG in the world, exporting a total of 26.87 million tons in 2017, of which 14.81 million tons went to Japan, 4.21 million to China, and 3.75 million tons to South Korea.[29] Malaysia has nine production trains, the newest of which started production in 2017 and is currently operating at 92 percent capacity.[30] It has also a new floating LNG train (FLNG) with a capacity of 1.2 million t/y.

Two of the LNG trains are owned by Petroliam Nasional Berhad (the Malaysian state oil company known as Petronas), Mitsubishi of Japan, and the Sarawak state government. Another train is owned by Petronas, JXTG Nippon Oil and Energy, Thailand's PTT PCL, and the Sarawak government. A fourth one is majority owned by Petronas with minority owners Royal Dutch Shell PLC, Mitsubishi, and Japan Petroleum Exploration Co. (JAPEX). The FLNG train is fully owned by Petronas.

ALGERIA

Algeria, one of the first LNG producers, currently has export capacity of 12 million t/y out of Arzew on the Mediterranean coast. The trains in Arzew were originally built for shipments to Europe and the east coast of the United States at Cove Point, Maryland. While the US shipments never materialized due to disagreements over prices, Algerian trains sell to France, Spain, and Turkey. However, these trains are only used at 49 percent capacity, likely because Algerian gas exports are now piped through three pipelines under the Mediterranean to Europe. Two deliver gas to the European grid through Spain, one via Morocco, and one to Italy, through Tunisia.[31] Hence, Algeria's exports do not impact LNG trade to Asia except that it displaces some shipments from Qatar or the United States to Europe, which can instead be offered on the Indian or East Asian markets.

Liquefying natural gas in Qatar. The world's largest refrigeration compressors cool natural gas and turn it into liquid.
Source: Shell/Flickr

28 *2018 World LNG Report*, International Gas Union, Appendix 2 and 3.
29 *GIIGNL Annual report*, 2018.
30 *2018 World Gas LNG Report*, 22.
31 Ibid., 16 and 22.

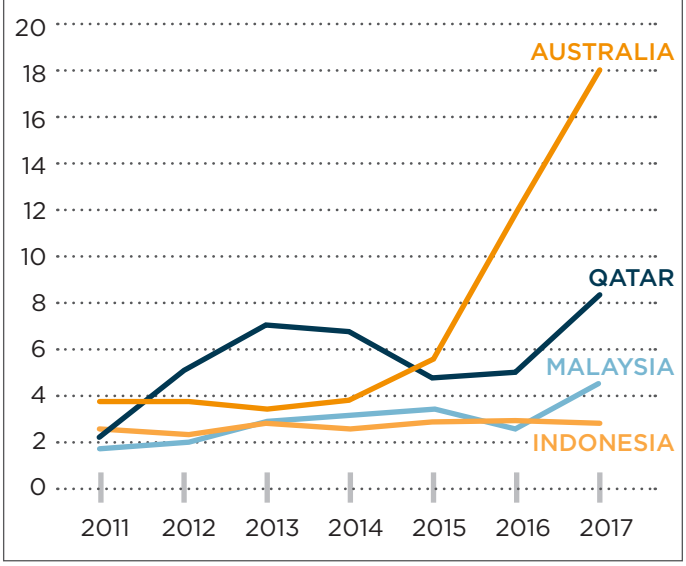
THE NEWER SUPPLIERS

AUSTRALIA

The decline in Qatar's market share in China is principally due to the rise of LNG production in Australia and Papua New Guinea, which have a combined market share in China of over 50.88 percent of total imports.[32] This is also due to China's apparent effort to diversify supplies.

The rise of Australia has been a major event in the global LNG picture. Australia's proven gas reserves are 1,923 bcm in 2018, providing ample supply to the LNG trains currently in place and under development. Australia and the Australian producers in Papua New Guinea currently export 63.9 million t/y of LNG, of which 7.7 million tons are coming from Papua New Guinea.[33] This amount is scheduled to increase by an additional 20 million t/y by the end of 2019 from plants currently under construction and 104 million t/y of additional capacity is under consideration.[34] Due to this increase in capacity and the proximity to markets in the region, Australia has now become the lead supplier to East Asia.

Figure 4: China's Top 4 LNG Suppliers
in million t/y



Source: *Middle East Economic Survey*, December 8, 2017: Volume 60, Issue 49.

Australia's dry natural gas production increased from 93.4 bcm in 2016 to 135.1 bcm in 2018. Most of Australia's gas production comes from the North West Shelf (NWS), which lies between the Carnarvon, Browse, and Bonaparte basins offshore Western Australia. NWS is the site for two of the country's largest LNG export ventures, namely the North West Shelf LNG (16.9 million t/y) and Gorgon LNG (16.2 million t/y). Data from the Australian Petroleum Production and Exploration Association (APPEA) shows that Western Australia accounts for 77 percent of total gas production, followed by Victoria.[35] Queensland is the largest producer of coal-bed methane (CBM), which is also called coal seam gas in Australia. Growth in natural gas production in recent years was supported by stronger output from feed-gas fields to Woodside Petroleum Ltd.'s Pluto LNG facility and the recent activation of Chevron Corp.'s new 9.2 million t/y Wheatstone LNG facility.

Australia's natural gas production is expected to further increase, supported by the start-up of two new LNG export projects in late 2018: Inpex's Ichthys LNG in offshore Northern Territory and Shell's Prelude FLNG in offshore western Australia, estimated to have a combined output capacity of 12.53 million t/y. These projects put the country on track to become the world's largest LNG exporter by 2019, but despite the numerous projects under consideration, 2019 may mark the end of Australia's list of multibillion-dollar LNG facilities.

Much of Australia's new production cannot be driven by greenfield developments due to high production costs in geologically difficult fields. Furthermore, new LNG exports may be limited by increasing regulatory barriers that seek to direct more gas to Australian consumers rather than to LNG exports and by envi-

32 *GIIGNL Annual Report*, 2018, 21, table on quantities received.

33 Computed from *2018 World LNG Report*, International Gas Union, 21.

34 *2018 World LNG Report*, International Gas Union, Appendix 3.

35 "Key Statistics," APPEA, 2018, 5, accessed November 6, 2018 at https://www.appea.com.au/wp-content/uploads/2018/05/APPEA_Key_Stats_2018_web.pdf.

ronmental opposition and concerns, which are driving onshore drilling bans and opposition to drilling in certain offshore fields. For example, Norwegian energy company Equinor ASA's plan to explore for oil and gas in the Great Australia Bight in South Australia's seas continues to encounter significant opposition from environmental groups, amid fears of an oil spill and potential damages to the local aquaculture industry. Local governments in South Australia remain opposed to oil and gas activities in the Bight.

New exploration off the country's eastern and southern coasts will be even more difficult to advance due to the areas' natural setting and stiff opposition from environmentalists. In 2017, Chevron and BP abandoned plans to drill exploration wells in the Bight, while Asset Energy Pty Ltd.'s plans to drill offshore of New South Wales (NSW) drew heavy criticism from the local government. Meanwhile, drilling bans and fracking moratoriums implemented at the local level across various states dampen the outlook for onshore exploration.[36]

Australia is also facing challenges with coalbed methane, subject to stringent regulation due to fracking's potential effect on local water supplies. Fracking is suspended across four states (NSW, Tasmania, NT, and WA) and permanently banned in one (Victoria), while south Australia has enacted a ten-year moratorium on hydraulic fracturing in the southeast Limestone Coast.

Given these dynamics, it is difficult for Australia to increase its LNG facilities and productions beyond the currently high level. Counterintuitively, Australia may end up importing LNG for its gas-hungry eastern markets, which would likely be more cost competitive compared to large-scale cross-state pipelines or having to divert supplies from export projects.

OMAN

Oman was an early LNG producer in the Middle East. The country's first two trains started in 2000 and its third in 2006, for a total capacity of 10.3 million t/y. Traditional gas reserves unexpectedly ran short in recent years, limiting production and partially idling its LNG trains. Oman's net exports stood at an estimated 9.6 bcm in 2017, down from a high of 10.1 bcm in 2016. Oman's gas reserves are estimated at 23.5 trillion cubic feet (tcf) in 2017 (0.7 trillion cubic meters, or tcf).[37] In 2008, when it became apparent that Oman's production could start declining, Oman arranged to import 2.1 bcm/y of natural gas from Qatar through the Dolphin pipeline, which crosses into Abu Dhabi.[38]

Fortunately for Oman, BP discovered and developed the Khazzan reservoir, one of the largest tight gas accumulations in the Middle East. The first phase of the Khazzan gas-field development was brought online in late September 2017 and will ramp up to an expected production of 10.28 bcm/y.[39] BP confirmed the final investment decision for the second phase of the Khazzan gas project in December 2017.

Until Khazzan, Oman's declining reserves had put it in the position of having LNG export capacity it could not fill with domestically produced gas, leading Omani officials to consider whether Iran could build a pipeline from Bushehr to the Omani coast and use the LNG facilities to export the first Iranian LNG. Officials from Iran's state gas export company, Oman's oil ministry, and private companies including Shell, Total SA, and Korea Gas Corporation held talks in February 2017 to discuss a possible subsea gas pipeline from Iran to Oman. However, together with BP, Oman has been able to harness large volumes of gas from Khazzan over the last two years and has be-

36 "BP Quits Plan to Drill in Great Australian Bight," *Wall Street Journal*, October 11, 2016, https://www.wsj.com/articles/bp-buries-plan-to-dig-in-great-australian-bight-1476170100; "Chevron Abandons Plan to Drill for Oil in Great Australian Bight," *Guardian*, October 12, 2017, https://www.theguardian.com/environment/2017/oct/13/chevron-abandons-plan-to-drill-for-oil-in-great-australian-bight; "Chevron Drops $400m Great Australian Bight Drilling Plans," *The Australian*, October 13, 2017, https://www.theaustralian.com.au/.../chevron...bight-drilling-plans/.../a5126cd6d615a514541c30d8da53285b.

37 *BP Statistical Review of World Energy*, 2018, 26.

38 World Energy Council data, accessed October 28, 2017, Worldenergy.org/data/resources/country/oman/gas/.

39 "BP Starts Production from Giant Khazzan Gas Field in Oman Ahead of Schedule and Under Budget," BP, September 25, 2017, https://www.bp.com/en/global/corporate/media/press-releases/bp-starts-production-from-giant-khazzan-gas-field-in-oman-ahead-of-schedule-and-under-budget.html.

Snow covered transfer lines are seen at the Dominion Cove Point Liquefied Natural Gas (LNG) terminal in Lusby, Maryland March 18, 2014. Credit: REUTERS/Gary Cameron

gun filling up its LNG trains, rendering the Iran-Oman project irrelevant.

One potential area for LNG demand growth is ship fuel, instead of bunker oil, due to the new International Maritime Organization rules on sulfur coming into effect in 2020. Most ships run on sulfur-emitting bunker oil, thus many are considering changing to sulfur-free LNG. In anticipation of this potential shift, Oman and Total have signed a memorandum of understanding to develop LNG bunkering facilities in Oman. While it remains to be seen whether this bet on bunkering will pay off, Oman is the first country to seek to establish an LNG bunkering facility, which would give it a major advantage in the Gulf bunkering industry.

RUSSIA

With the second-largest gas reserves after Iran, Russia is also the second largest producer of natural gas with 635.6 bcm in 2017, behind the US production of 734.5 bcm. Russia is, however, the largest exporter with 215.3 bcm/y, and it is the main supplier of natural gas to Western Europe, with 189.4 bcm/y,[40] through an intricate network of pipelines. As mentioned earlier, Russia is also planning to pipe gas to China via the Altai pipeline to Urumchi in Xinjiang.

Total 2017 LNG exports are listed by BP's statistical review at 15.5 million t/y, and are mainly to Japan (9.9 mt/y), South Korea, and Taiwan. This figure, however,

40 *BP Statistical Review of World Energy* 2018, BP, 34.

may be optimistic, as the only LNG facilities that are fully operational today are those in Sakhalin Island in East Asia, through a joint venture with Royal Dutch Shell, Mitsui & Co., and Mitsubishi. Sakhalin II has a capacity of 11.6 million t/y.[41] Russia only started exporting from its Yamal production area in the north of the country in December 2017. Production there is expected to total 3.3 million t/y in 2018 and 16.5 million t/y for 2019.[42] The Yamal joint venture involves Russia's Novatek (50.1 percent), Total (20 percent), and China's state-owned China National Petroleum Corporation (20 percent).

Russia has ambitious plans to develop its LNG production much further with a third train in Sakhalin, greenfield developments in Vladivostok in the east, and on its western shore on the Baltic Sea, for a total by 2040 of between 103 t/y and 118 million t/y.[43] Russia is investing in numerous ice-capable LNG tankers as well as large atomic-powered icebreakers to be able to use the northern route to East Asia, cutting the voyage from the Yamal peninsula to East Asia to twenty-three days from thirty-four days via the Suez Canal and giving Russia further access to the Asian market.[44]

UNITED STATES

US Production, Capacity, and Costs

In the 1980s and 1990s, US natural gas reserves were considered to be on the decline. However, with the astonishing development of shale gas technology, the opposite is true and the market price of gas is based on the realization of now-plentiful reserves. The EIA estimated US recoverable reserves of proved natural gas at 464.3 tcf (13.07 bcm) in 2014,[45] with shale gas reserves accounting for 200 tcf.[46] The technology to access reserves is rapidly improving, which in turn increases the level of recoverable reserves at declining costs. Shale production in the United States is currently estimated at 13.5 tcf annually,[47] and it seems likely supply will keep increasing for the near and medium term.

US gas production costs are among the lowest in the world, as most of the gas brought to LNG producers is extracted from onshore wells which are much cheaper to drill and operate than the deep offshore ones or the extreme environments of many existing or prospective producers including Australia, Mozambique, Russia, and Norway. Newfound shale supplies have caused prices to decline drastically from $8/MMBtu at the wellhead in 2008 to about $3/MMBtu in late 2017 and $4.31 in November 2018. However, even at these low prices, the natural gas industry is still expanding.

Thus, as LNG capacity increases rapidly in the Gulf of Mexico, US LNG producers will likely continue to aggressively develop their markets worldwide. Cheniere Energy Inc. is the largest US producer, with four trains running at Sabine Pass with a total capacity of 18 million t/y, while Dominion Cove Point LNG LP produces 5.5 million t/y out of its Cove Point terminal in Maryland. Construction is proceeding on twelve plants for a total capacity of 12.5 million t/y, including Cheniere's third phase of Sabine Pass, which adds new trains with the huge capacity of 9 million t/y. These twelve plants are scheduled to come on line by the end of 2019, when total capacity in place is expected to reach 69.75 million t/y[48] (see Appendix 1). There are thirteen projects being evaluated by the Federal Energy Regulatory Commission (FERC)[49] and another thirty-four other projects being evaluated by investors,[50] with possible total capacity of over 280 million t/y. Given the competitive nature of LNG, it is unlikely all these projects will see daylight, but even a small portion of them would increase competition for Qatari and Australian producers and limit

41 "Sakhalin-2: An Overview," Royal Dutch Shell, www.shell.com/about-us/major-projects/sakhalin/sakhalin-an-overview.html.

42 "Yamal LNG Project Begins Gas Exports," World Oil, December 8, 2017, website accessed at www.worldoil.com/news/2017/12/8/yamal-lng-project-begins-gas-exports.

43 Eugene M. Khartukov, "Russian LNG Exports to Grow Through 2040" Oil and Gas Journal, September 3, 2018, 84-88.

44 "LNG Shippers Set to Gain as Arctic Sea Routes Open Up," *Bloomberg*, September 3, 2018.

45 "U.S. Crude Oil and Natural Gas Proved Reserves, Year-end 2017," US EIA, November 2018, https://www.eia.gov/naturalgas/crudeoilreserves/

46 US reserves are, of course, much lower than those of Qatar (866.2 tcf), Russia (1,139.6 tcf), or Iran (1,201.4 tcf).

47 "U.S. Crude Oil and Natural Gas Proved Reserves," US EIA.

48 *2018 World LNG Report*, International Gas Union, 71-72.

49 "North American LNG Export Terminals: Proposed," US Federal Energy Regulatory Commission, October 23, 2018, accessed at https://ferc.gov/industries/gas/indus-act/lng/lng-proposed-export.pdf.

50 *2018 World LNG Report*, International Gas Union.

price increases even if Chinese demand continues to grow rapidly.

The cost of US LNG production is predicated on the costs of natural gas at the Henry Hub in Louisiana. If these prices remain in the range of $3/MMBtu to $4/MMBtu, and given the present $10/MMBtu landed price in Asia, US producers can compete aggressively with Qatar despite the higher shipping costs. Furthermore, US producers will increasingly be able to take business from Qatar in Europe, perhaps creating downward pressure on Asian prices.

The US Export Regulatory Environment

In the US, one of the most difficult and costly parts of developing the LNG industry and exports has been the regulatory process. After much political wrangling, in late 2015 Congress granted companies the ability to export natural gas without exception to countries with which the US has a free trade agreement (FTA); exports to non-FTA countries like China require applications, which are reviewed by the US Department of Energy (DOE) and FERC and are typically approved promptly.

The Present US Administration's Policy and Trade Tensions

The Trump administration has talked tough on trade with China, and trade tensions will strongly impact US LNG producers, as China announced that LNG exports from the US would be subject to substantial tariffs. On the other hand, US producers can find profitable markets in Europe, other Asian countries, and Latin America, which in turn could displace Qatari, Australian, or other suppliers, who could sell their gas to China instead. Hence, the impact of tariffs on US firms in China would be minimal. The displacement of Qatari LNG in Europe or Latin America could actually allow the US suppliers to increase their margin due to lower shipping costs. On the other hand, China could lose some of its ability to diversify its supplier base, risking higher costs and security of supply.

OTHER NEW POTENTIAL PRODUCERS

The potential suppliers listed below will be looking to export a large portion of their LNG to India and East Asia if and when they become fully operational, meaning they could compete with supplies from Australia and Qatar. They will also have a major geographic advantage over supplies from the United States in competing for Asian markets as these supplies would not have to go through the Panama or Suez Canal.

TANZANIA

Large offshore reserves have attracted a number of large international oil companies to Tanzania. However, the country's apparent lack of political and legislative support for their potential large investments make the oil companies wary, causing them to delay final decision-making about investing in a new onshore LNG production facility. When and if finalized, the planned export terminal would have capacity of 1.6 million t/y of LNG; however, no export is expected until 2027, at the earliest.

MOZAMBIQUE

Recent gas discoveries off the coast of Mozambique have raised interest in the country as a potential large gas producer and LNG exporter. Mozambique's proven gas reserves are estimated at 2.8 tm^3. LNG production capacity is expected to start with the arrival of "the Coral FLNG Project," a floating LNG facility to be operated by ENI SpA of Italy. The project's main partners are ENI, ExxonMobil and CNPC of China. The facility is expected to begin exporting LNG in 2022 with an estimated capacity of 3.5 million t/y.[51]

Other projects include the Golfinho/Atum Field Development Plan by Anadarko Petroleum Corp., approved by the government in March 2018. This project includes an onshore LNG plant scheduled to start in 2024. The project is a joint venture with Mitsui of Japan, three Indian oil and gas companies, PTT of Thailand, and the Mozambique oil company.[52]

CAMEROON

Thanks to the arrival of the Hilli FLNG vessel, Cameroon joined the club of LNG exporters in 2018, with export volumes of 1 million tons in 2018. Development of LNG in Cameroon, located in West Africa, will likely only impact Asian markets in that it may potentially displace some of the US and Qatari supplies to Europe, which may end up impacting the markets in Japan, China, and Korea.

CANADA

According to Canada's National Energy Board (NEB), the country had 170 billion barrels (bbl) of proven oil reserves and 72 tcf (2.07 tcm) in gas reserves as of the end of 2017.[53] Canada's dry natural gas production is estimated at 168.2 bcm in 2018,[54] while LNG exports are a very modest 1.3 million t/y. The majority of Canada's natural gas production is in the western provinces of Alberta and British Columbia, and if Canada brings these gas supplies from the Great Plains to the Pacific Coast it would enable potential large LNG exports to Asia. However, the federal approval process for pipelines in Canada is lengthy, while continued legislative hurdles coupled with strong environmental and indigenous opposition are hampering the Alberta to British Columbia gas pipeline. However, Canada did approve two projects in 2018. The first one linked to the 47-kilometer Woodfibre gas pipeline, which includes a new train of 2.1 million t/y and was approved by the federal government in March 2018.[55] The NEB approved the much larger Kitimat LNG project and pipeline in October 2018. This plant is expected to produce 10 million t/y, and the overall project is expected to cost 40 billion Canadian dollars. It is a joint venture between Royal Dutch Shell, Mitsubishi, Petronas, PetroChina Co., and Korean Gas Corp.[56]

MEDITERRANEAN BASIN

In recent years, the countries bordering the southeastern Mediterranean have discovered large offshore gas

51 *GIIGNL Annual LNG Report*, 2018, 23.

52 Mitch Ingram, "What Next for the Asia Pacific Gas Market?" Anadarko Petroleum Co., paper presented at the World Gas Conference, June 2018. https://www.anadarko.com/content/documents/apc/news/WGC_Presentation_2018.pdf.

53 "Energy Future 2018," National Energy Board of Canada, 44, table 3.2, https://www.neb-one.gc.ca/nrg/ntgrtd/ftr/2018/2018nrgftr-eng.pdf; "Natural Gas Facts," Natural Resource Canada, https://www.nrcan.gc.ca/energy/facts/natural-gas/20067.

54 Ibid.

55 Woodfibre LNG Ltd., https://www.woodfibrelng.ca/the-project/about-the-project/.

56 "$40B LNG Project in Northern B.C. Gets Go-ahead," *CBC*, October 2, 2018, https://www.cbc.ca/news/canada/british-columbia/kitimat-lng-canada-1.4845831.

reservoirs, sparking a conversation about production, exports, and potential LNG production. The development of East Mediterranean resources would have a significant impact on the overall LNG market as the substantial gas production potential in Egypt, Cyprus, Israel, and Lebanon collectively could contribute to LNG exports from the region, which could displace large amounts of LNG now purchased by Europe and India. While the gas from the offshore fields of Zohr in Egypt, Leviathan in Israel, and Aphrodite in Cyprus could be sent to Europe by pipeline—a most difficult but feasible project—it could more easily be liquified, perhaps in the underutilized Egyptian trains and exported as LNG, which could easily reach South Asia and East Asia through the Suez Canal.

The first country in the region to develop its offshore reservoirs and LNG export capacity was Egypt, which operated a 7.5 million t/y LNG export facility in Idku and a 5 million t/y facility in Damietta, exporting LNG around the world as well as piping gas to Jordan and Israel. After 2013, gas production from the West Nile Delta and other offshore fields started declining and could no longer feed the LNG trains, forcing Egypt to start importing LNG to meet its needs.

Egypt's fortunes changed dramatically in August 2015, when ENI discovered Zohr, a 608 bcm field north of Alexandria. ENI started production from Zohr in late 2017 and is now pumping 2 bcf per day (56 mcm/d) for the Egyptian grid. Most of the projected production from the Zohr field is allocated domestically, namely for power plants and fueling industries, and is not sufficient to start operating the existing LNG trains.

There have been major discoveries off the coasts of Israel and Cyprus. Israel discovered the large offshore Tamar and Leviathan fields in 2009-2010. Texas-based Noble Energy, which holds a 25 percent interest in the 200 million m^3 Tamar field and 39.66 percent interest in the 622 million m^3 Leviathan field,[58] extracts and provides about 65 percent of Israel's gas demand from the Tamar field and is developing the Leviathan field, which is currently 60 percent completed. Cyprus discovered two large offshore fields, the 10.5 tcf Aphrodite field and the 12.5 million tcf Calypso field. Production from Aphrodite is expected to start in 2019. Cyprus and Egypt signed an agreement in September 2018 to construct a pipeline connecting the two countries which will pipe the gas from the Aphrodite field to Egypt's Idku LNG train.[59] Cyprus is also considering building an offshore LNG facility with a capacity 3.7 million t/y at Vasilikos, although it is unlikely that domestic gas production would be sufficient to support both export to Egypt for liquefaction and a domestic LNG train.

IRANIAN GAS

Iran's gas reserves, at about 33.2 tcm, are the largest in the world. The biggest single gas field in Iran is South Pars, in effect the northern portion of the field called North Dome by Qatar. Iran produces about 223 bcm/y, but despite this high production and potential, Iran exports only 8.9 bcm/y to Turkey and 1.7 bcm/y[57] to Turkmenistan via pipeline, and it does not produce any LNG for export. While there have been several potential LNG projects with CNPC, CNOOC, and Total, all fell through primarily because the technology for LNG trains is largely controlled by Western firms that would be targeted by primary and secondary sanctions (re) imposed by the United States in November 2018.

Most Iranian gas production is used for local energy needs, heat, and electricity. It is also used for reinjection to maintain pressure in declining oil fields. Finally, a major use is as feedstock for Iran's growing chemical industry, which produces methanol, fertilizers, styrene, polymers, and ethylene-based products. The chemical industry is a high priority for Iran, with plants in numerous cities fed by a 1,200-km long ethylene pipeline.

Substantial domestic gas production provides Iran with about 900,000 b/d of condensates (basically ethane, propane, butane, and heavier carbon molecules), which have an excellent market worldwide. However, the US sanctions imposed this November apply to these condensates as well as crude oil, effectively cutting Iran off from a large market.

Counterintuitively, most gas users in Iran suffer from low gas supplies. Despite high potential, Iran's gas fields suffer from low maintenance and require advanced technologies to improve output, which are controlled by foreign companies that would be subject to secondary sanctions if proven to work with Iran.

57 *BP Statistical Review of World Energy* 2018, BP, 34.

58 "Noble Energy to Sell $800 Million Stake of Tamar Natural Gas Field," *Jerusalem Post*, October 29, 2018.

59 "Egypt, Cyprus Sign Accord to Build Gas Pipeline," *Middle East Monitor*, September 20, 2018, https://www.middleeastmonitor.com/20180920-egypt-cyprus-sign-accord-to-build-gas-pipeline/

THE EVOLVING GLOBAL LNG MARKET STRUCTURE

PRICING ISSUES

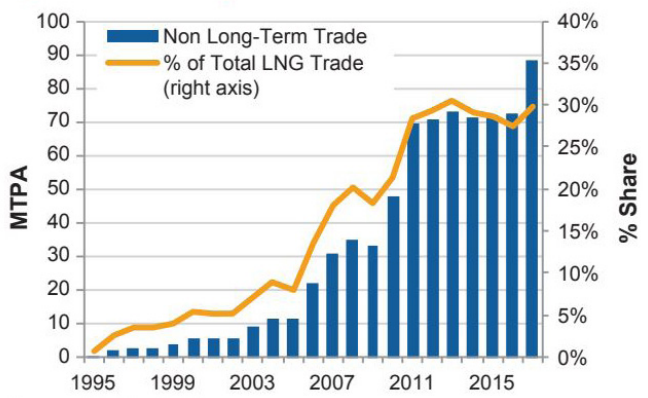
LNG prices are usually based on the price of oil. The leading price index for natural gas in Asia is a percentage of the Japanese Crude Cocktail (JCC) in Tokyo, with a ceiling of around $18/MMBtu and a floor of around $4/MMBtu. The exact price indexing, ceilings, and floors are provided in each contract with the buyers and are usually for a period calculated to match the loans provided by the international lenders. The financing facilities for LNG plants and ships are extremely complex, and loan durations will vary from up to seventeen years for LNG ships to fourteen to twenty-seven years for complex loan and bond financial structures to finance large LNG trains. In short, these financial facilities will average tenders of about twenty years, matched by purchase contracts by prime buyers of the same duration, providing lenders with some assurance of cash flow for the life of the loans.

As the price of oil increased between 1998 and 2014 from $12/barrel to $120/barrel, the price of LNG went from floor to ceiling, to Qatar's great benefit. On production of 77 million t/y this corresponded to an increase in gross income for Qatar from $15.6 billion to $71.8 billion per annum. However, with the oil price decline from its summer 2014 peak to the average of $50 to $60 in 2016, LNG prices in China and most of East Asia were down to between $5.5/MMBtu and $6/MMBtu.[60] Prices rebounded in January 2018 to a spike of $9.8/MMBtu, for the North East Asian price, providing a major boost to Qatar's finances.[61] Already in 2017, Qatar's gross income stood at about $67.5 billion and it is expected to reach $80.9 billion by the end of 2018.[62]

While 70 percent of the LNG market is indexed on the price of crude oil, this pricing arrangement is increasingly being replaced by a spot price which itself is strongly influenced by the price at the Henry Hub in the United States. At the time of writing, the spot price is lower than prices based on oil formulas. In 2017, 28.7 percent of all shipments, around 84.2 million tons, were done on a spot basis.[63] The percentage of spot versus long-term contracts is increasing rapidly as the decoupling of pricing for natural gas and crude oil is becoming more prevalent. The decoupling of gas and oil is basically due to the ample supply of shale gas production in the United States, the result of great progress in US shale-gas extraction technology. Furthermore, there have been increases in LNG processing facilities worldwide, which have greatly increased supplies.

Demand for natural gas is largely driven by two main factors. First, natural gas emits less CO2 and particulates for the same Btu output than coal and oil, making it a fuel more adapted to the fight against greenhouse gas emissions and air pollution in major cities like Beijing. Second, as mentioned above, gas costs less per Btu produced than oil, attracting large-scale utility companies. In 2017, one MMBtu costing $2.90 in the US market and $8.90 landed in China corresponded to an oil-generated MMBtu of about $12 when oil was at $70/barrel. In other words, until renewables like solar and wind backed by huge (and currently expensive) storage facilities can become low cost, the use of natural gas will grow and replace

Figure 5: Volume of LNG Spot Transactions



Sources: IHS Markit chart, as presented in *2018 World LNG Report*, International Gas Union

60 Author's own computation.
61 *2018 World LNG Report*, International Gas Union, 17.
62 *Middle East Economic Digest*, August 3, 2018.
63 *2018 World LNG Report*, International Gas Union, 16.

coal and oil, as is happening in the United States and China. As seen before, the Chinese decision to favor gas over coal resulted in a 42.3 percent increase in imports of LNG in 2017, after an increase of 36.9 percent in 2016.[64]

SHIPPING COSTS

Spot charters are used for about 30 percent of overall LNG shipping, and prices can vary widely depending on the demand for ships and their size. A charter for a standard (150,000 to 180,000 m^3) LNG tanker went for $27,000 per day in January 2017, $33,000 in July 2017, and about $92,000 in June 2018. The cost hit $150,000/day in January 2011.[65] Thus, distance, and therefore the number of days at sea, affects the value of the LNG shipment to the supplier.

The LNG trains in Perth, in Western Australia, are relatively close to China, at 4,794 nautical miles. In comparison, Ras Laffan in Qatar is 6,804 miles. On a charter cost of $150,000 per day, the shorter distance makes a difference of $0.45 per MMBtu. Furthermore, the actual charter is only a part of the cost, as the charterer will incur the cost of fuel, insurance, commissions, potentially the canal fees for Panama or Suez, and depending on the shipper's arrangements, the cost of the return.

The cost of fuel used by tankers will vary according to the engine technology of the ship. The most efficient boats use dual fuel diesel electric systems (DFDE), which use the boil-off LNG in the cargo more efficiently than more traditional steam turbines (ST). Reflecting the efficiency of the ships, DFDE will usually cost a great deal more per day of charter yet be less costly to operate.

It is, of course, difficult for industry outsiders to estimate shipping costs with precision given constantly evolving variables: market volatility of the charters, size of available ships, speed of operation (from 10 to 19 knots), fuel types, Panama or Suez transit fees, insurance costs, brokerage fees, etc. However, a study published by the Oxford Institute for Energy Studies estimated the cost of LNG charters for DFDE shipping from Sabine Pass to Shanghai to be $1.06/MMBtu in July 2017 and comparable ST shipping at $1.26/MMBtu, which included the charter, cost of fuels, harbor costs, cost of Panama Canal transit, insurance, and commissions.[66] The same study estimated the total cost of a DFDE on this route via the Panama Canal using a Panamax (i.e., a ship sized to go through the canal) of 160,000 m^3 at a speed of 19 knots/h, amounted to about $3.5 million, of which $1.5 million was the actual charter. The average speed of 19 knots/hour may be hard and expensive to maintain for a whole trip, and it may be more conservative to use the estimated speed of 14.6 knots/hour.[67] Furthermore, the chartering daily rate, of $33,286 in June 2017 used for this computation has gone up to $92,000 in June 2018 for the same route, thus increasing the overall cost to $5.6 million, or about $1.89/ MMBtu.[68]

Using publicly-available information, a rough estimate of the cost of shipping from Qatar to Shanghai in June 2018 would have been about $92,000/day for 19 days based on a total shipping cost of about $0.63 per MMBtu for a 160,000 m^3 ship.[69] At the same time, shipping from Sabine Pass in the Gulf of Mexico would have been higher due to the limit imposed on ship size by the Panama canal and the substantially longer distance, which increases the duration of the trip to twenty-nine days, assuming the same speed of 14.6 nautical miles as in the previous example, as well as the Panama Canal fees (one way) of about $334,000, which would increase the actual shipping cost to about $0.99 per MMBtu.[70]

With LNG pricing computed on a CIF basis, it is important for exporters to estimate the cost of insurance. The policies are generally quoted and issued by the large Western and Japanese insurance companies, who in turn will reinsure the policy by selling down slices of the risk to numerous insurance groups worldwide. Due to the widespread sharing of risk, and fairly transparent terms and conditions in the industry,

64 *2018 World LNG Report*, International Gas Union, 2018, 6.

65 Ibid., 40.

66 Howard Rogers, *The LNG Shipping Forecast: Costs Rebounding, Outlook Uncertain*, Oxford Institute for Energy Studies, updated March 2018.

67 Greg Miller, "Why LNG Shipping Rates Are Hitting Highs," IHS Markit special report on the Fairplay website, https://fairplay.ihs.com/commerce/article/4303981/special-report-why-lng-shipping-rates-are-hitting-highs.

68 Ibid.

69 Author calculation based on a speed of 14.6 knots/h, plus $20,000 x 19 days fuel, no canal fees, and other costs (port fees, agency and insurance) of about $300,000, i.e., a total shipping cost of about $0.63/ MMBtu for a 160,000 m^3 ship. Of course, the Qatari ships are larger than the 160,000 m^3 mentioned here. They would be more efficient, providing some substantial savings, for shipping costs of perhaps as low as $0.40/MMBtu.

70 Rogers, "The LNG Shipping Forecast"; the speed was indicated in Fairplay, which quoted a JPMorgan Report.

premiums tend to be quite constant and predictable. While crude oil shipments are insured by the buyer, insurance of LNG cargoes are covered by the seller. The Oxford Institute for Energy Studies study estimates the insurance for LNG charters at $2,600/day.[71]

Shipments from the Middle East, however, may not be as easily estimated as they could be severely impacted by tensions in the Arabian/Persian Gulf. In case of conflict in the Gulf, LNG tankers would make prime targets, which would be reflected by large increases in insurance costs. During the 1991 Gulf War, prices for insurance on oil tankers went up to $1 million per day for ships in the Gulf. Given tensions between the Arab states of the Gulf allied to the United States and Iran, the whole Nakilat fleet could be subject to punitive insurance pricing. At this time, attacks on Qatari tankers remain unlikely. The presence of numerous naval forces, especially the US Fifth Fleet minimizes the potential threat to Gulf shipping through the Strait of Hormuz. That said, the presence of these forces also reminds importers, especially in East Asia, that there is a strategic risk in dealing with the Gulf, including Qatar, and leading these importers to diversify their sources of LNG regardless of cost.

Should there be a major increase in tensions resulting in military conflicts between Saudi Arabia and Iran and/or between Iran and the United States, the main economic victim (other than Iran) would be China, which would experience a tremendous increase in crude oil and LNG import prices. Because of this, China would likely do everything it can to avoid armed conflict in the Gulf. It also means threats from some Iranian entities, like the Iranian Revolutionary Guard Corps (IRGC) to block the Strait of Hormuz are probably bluster, as Iran would find itself without an export outlet. Blocking the strait could also inflict great economic pain on China, which would mean Iran could lose its main ally in its problems with the United States and its Arab neighbors.

Chinese LNG tanker ship Hai Yang Shi You 301 docking at Benoa. Source: BxHxTxCx/Wikimedia

Figure 6: World LNG Estimated Landed Prices, October 2018

Source: US Federal Energy Regulatory Commission, www.ferc.gov/market-oversight/mkt-gas/overview/ngas-ovr-lng-wld-prest.pdf

Other risks include the potential for piracy in the northern part of the Indian Ocean. Attacks on ships have declined in the past three or four years due to the great efforts made by the United States, France, China, India, and others, but are still a threat and require expensive countermeasures by ship owners.

CHOKE POINTS TO THE CHINA TRADE

China has a strategic need to minimize shipping through maritime choke points over which it has little influence, like the Straits of Hormuz and Malacca, and thus will look to work with Australia whose shipments bypass these waterways. China-bound ships from Qatar deal with the two previously-mentioned choke points, as well as piracy, while shipments from the United States only transit one choke point, the Panama Canal. For China, a diversification policy will balance the cost of shipping versus supply-side risk. Unless political differences with the United States or other countries affect trade, China would likely prefer to have shipments from all three main suppliers, Qatar, Australia, and the United States, as well as other suppliers when they become available, to balance their portfolio and diversify risk and cost.

71 Rogers, "The LNG Shipping Forecast," 26, https://www.oxfordenergy.org/wpcms/wp-content/uploads/2018/02/The-LNG-Shipping-Forecast-costs-rebounding-outlook-uncertain-Insight-27.pdf.

GENERAL PRODUCTION ISSUES

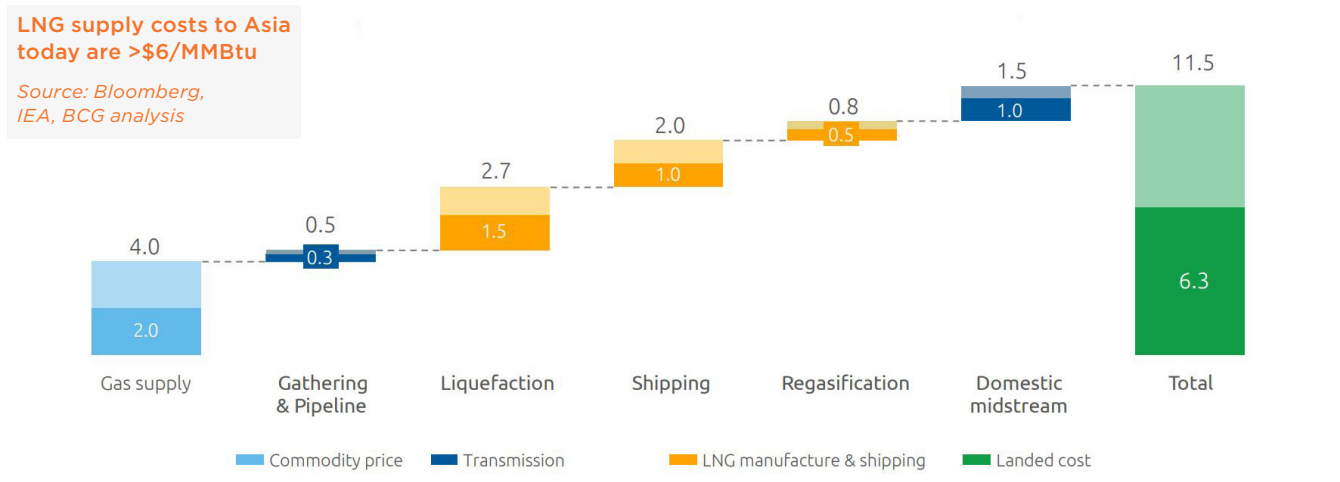
Current global LNG production capacity is 369.4 million t/y and is expected to increase to 875 million t/y by the 2020s.[72] As noted in this report, there are numerous potential projects, with 92 million t/y capacity under construction and many more under consideration around the world, notably in Russia, Tanzania, the United States, and Qatar.[73] Most of these projects have very different cost of production frameworks, with the lowest costs still in Qatar where the government may not be charging its producers for the gas feedstock from the North Dome at a level which would be expected from other gas producers. The actual Qatari cost of gas extraction is only that incurred by the joint ventures operating in the offshore fields of the North Dome, i.e., the cost of drilling and extracting the gas, bringing it onshore, and then putting it through expensive LNG plants.

In the United States, large LNG producers pay market price, currently between $3/MMBtu and $4/MMBtu, for their gas at the Henry Hub distribution center in Louisiana. LNG producers then pipe the gas to plants on the Gulf of Mexico, where the gas is processed through the LNG trains, which adds a tolling fee to the final LNG pricing computation.

Estimating LNG costs for the very complex LNG processes is challenging. In a short nontechnical paper, it is difficult to gain accuracy beyond a "back of the envelope" assessment. Cheniere's LNG liquefaction trains in Sabine pass are at this time the largest in the United States. The LNG produced there is sold at the cost of natural gas at Henry Hub plus its tolling fee, which varies from $2.25 to $3/MMBtu. Hence, shipments to China, prior to regasification, would vary according to the Henry Hub prices, the negotiated tolling fee, plus the shipping cost. As of late 2018, based on this calculation the price would be about $8.44/MMBtu ($4.30 for gas, $2.25 for tolling, $1.89 for shipping).

Methane makes up the largest portion of the natural gas produced. Other products will include ethane, propane, butane, and other heavier molecules. The amount of natural gas liquids (NGLs) in methane

Figure 7: Typical LNG Cost Structure ($/MMBtu)



Source: International Gas Union, *Global Gas Report 2018*

72 *2018 World LNG Report*, International Gas Union, 4.
73 Ibid., 19.

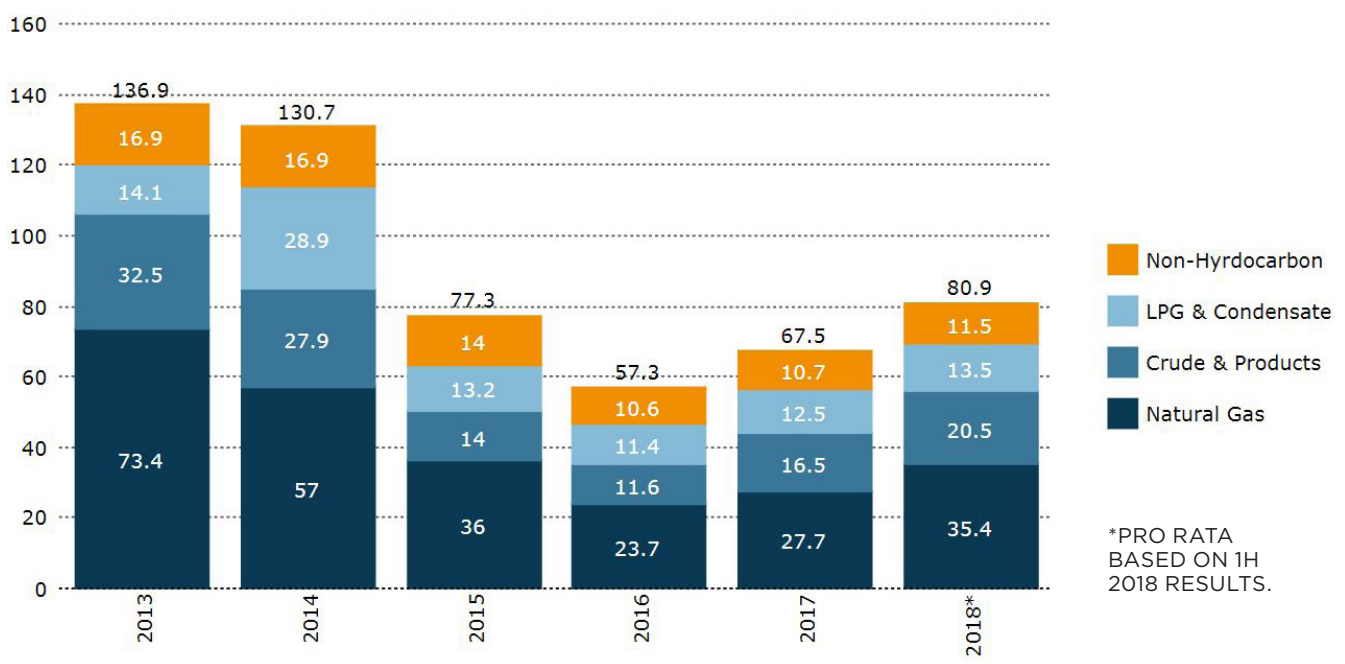
vary from one field to another, but often will be between 5 percent and 10 percent of the total output. These NGLs are of great value, especially for the petrochemical industry, so producers will separate some or all of them, depending on buyers' requirements, from the raw natural gas. The LNG will not include all the NGLs extracted along with the methane from any given field. The LNG producer will usually offer its gas product with specific amounts of NGLs, which affects the final price paid by buyers. For example, Qatar will offer LNG that includes 90.1 percent methane, 6.43 percent ethane, 1.66 percent propane, and 0.74 percent butane.[74] In the Qatari case, the gas liquids (here called LPGs and condensates) add about 55 percent to the LNG income of Qatar.[75]

QATARI PRODUCTION COSTS AND REVENUE ESTIMATES

Qatar produces 80.9 million tons of LNG per year (i.e., about 4,200 trillion Btu/y) and has invested around $90 billion in LNG and extraction infrastructure to achieve this level of production. If depreciated over twenty years, the depreciation cost would be about $5.5 billion per year, less than 0.137 cents/MMBtu. While Qatar does not release how much it charges for the North Dome gas to the LNG facilities, the Qatari state incurs the opportunity cost of not using the gas from the North Dome in other profitable ventures, like for example using the gas distributed to Abu Dhabi through the Dolphin project, i.e., $1.40/MMBtu.

According to the 2018 Global Gas Report, the total cost of bringing LNG to the market varies between $6.3 and $11.0 per MMBtu.[76] Qatar will rank in the lowest part of this range because: (1) Qatar may not charge its own companies for natural gas extracted from the North Dome, although it may be paying a fee to its partners who are extracting the natural gas from this offshore field; and (2) the estimated cost of transporting natural gas from extraction to the LNG plant in the report is about $0.5/MMBtu; however, this number is probably close to zero as the distance between the Qatari fields and the LNG plants is very small. Thus, an estimate of the cost of gas production in Qatar to the preregasification level mentioned in

Figure 8: Qatar's Export Revenues



Source: *Middle East Economic Survey*, August 3, 2018

74 *GIIGNL 2018 Annual Report*, LNG Characteristics, 22.

75 "Qatar's Export Revenues Hit A Four-Year High Despite Ongoing Embargo," *Middle East Economic Survey*, 61, no. 44 (2018).

76 *2018 Global Gas Report*, International Gas Union, 28.

the Global Gas Report would be around $2.5/MMBtu, i.e., an annual cost of about $10 billion.

The Qatari cost of transportation to Asia and to Europe is cheaper than US LNG, which, as seen above would be in the range of $0.70/MMBtu to China. As of July 2018, FERC estimates landed price in China at $9.85. At July 2018 landed prices on sales at CIF Shanghai, Qatar may receive a net back of $6.25/MMBtu ($9.85 landed price minus cost of production at $2.50 and transport at $0.70).

The *Middle East Economic Survey* estimates Qatar's income from natural gas at $35.4 billion in 2018 (see chart on previous page), part of total exports of hydrocarbons, petrochemicals, and gas-based fertilizer income of $80.9 billion expected for 2018, up from $67.5 billion in 2017 and $57.3 billion in 2016. LNG accounts for 40 percent of Qatar's exports, while oil accounts for 25 percent, natural gas liquids 17 percent, and fertilizers and chemicals around 15 percent.

Qatar runs fourteen LNG trains in two industrial cities (Ras Laffan and Mesaieed) through joint ventures with various international firms. Foreign companies hold an average of 30 percent equity share in the ventures. The income figures above include the JV partners' income, meaning the actual net income to Qatar from LNG would be net of payments to the joint ventures of about $27 billion in 2018, up from $19.4 billion in 2017 and $17.6 billion in 2016. By the same token, since all the hydrocarbon and industrial ventures of Qatar are in joint ventures with foreign partners, it seems that the actual income of Qatar from all of its hydrocarbon productions would be $56 billion in 2018, up from $43 billion in 2017 and about $40 billion in 2016. Netting out the budgeted state expenses $57 billion[77] leaves Qatar with a relatively small deficit in 2018, but a vastly improved financial position from the deficits of many tens of billions of dollars per year in 2017 and 2016.

However, Qatar is likely to be spending a great deal of money beyond the official budget to counter the Saudi/UAE-led diplomatic and trade embargo, as it seeks to build its relationship with Western powers by buying very large weapon systems including the French Rafale, the British Typhoon, the Franco-German Eurofighter, and countless US systems. It has been reported that Qatar is investing £138 billion ($173 billion) on the 2022 World Cup.[78] In addition, Qatar spends unknown amounts in support of various political and military movements and entities including the Muslim Brotherhood, the Turkish government, and certain Syrian rebel groups.

Including all these off-budget items, it seems Qatar likely has had to dip into its various currency reserves, including the ones QIA manages in a very opaque manner. If all the off-budget expenses were included in a breakeven computation of LNG, the net back return of LNG to Qatar per MMBtu would be very substantially lower than the $6.25 mentioned above.

77 "Qatar 2018 Budget Sees Modest Rise in Spending, Marginally Smaller Deficit," *Reuters*, December 13, 2017, https://www.reuters.com/article/us-qatar-budget/qatar-2018-budget-sees-modest-rise-in-spending-marginally-smaller-deficit-idUSKBN1E70YL.

78 "Qatar World Cup in 2022 Could Cost £138 Billion According to Financial Analyst," *Telegraph*, September 8, 2011, https://www.telegraph.co.uk/sport/football/world-cup/8749931/Qatar-World-Cup-in-2022-could-cost-138-billion-according-to-financial-analyst.html.

CONCLUSION

Global LNG supply and demand are increasing rapidly, with new suppliers and stronger appetite for the fuel in China and India. In 2018, LNG prices have gone up substantially in great part due to the rapid increase in oil prices in 2017 and 2018. Since November 2018, oil prices have been declining, and LNG prices will likely follow the downward trend. However, the price of LNG is no longer completely linked to the price of oil. With more than 30 percent of the whole LNG trade being done on a spot basis without reference to an oil benchmark, the price for LNG increasingly reflects the demand and supply of LNG, rather than that of crude oil or of piped gas. Both new suppliers, such as Australia and the United States, and the needs of buyers spurred growth in the spot market. The large increase of Chinese demand and the diversified types and location of buyers have contributed to breaking the pricing link with crude oil.

Indian and Chinese gas-demand growth will continue as natural gas increasingly becomes the fuel of the near future, replacing coal and some crude oil until renewables start taking over in the distant future. Fortunately, the very large increase in demand expected from the two most populated countries in the world may not lead to dramatic price increases, as new supplies are assured for the near future. Hence, competition for Asian markets between Australia, Qatar, and the United States is not a zero-sum game, as demand can be met from diversified old and new producers.

Since contracts are usually CIF, the brunt of competition is born mainly by the suppliers. Suppliers located far away will net back less than the closer ones. In East Asia, especially, where the distances to the producers are so enormous, shipping will be most important. On the other hand, producers with low cost of LNG manufacturing will have an advantage in obtaining a larger netback income. Both Qatari and US suppliers have low costs of production, while Australia and Qatar have a distance advantage compared to the United States, which allows them to have a lower cost per MMBtu CIF Shanghai or Yokohama. Qatar also controls its shipping fleet, while US and Australian producers depend on an unpredictable charter market. Hence, in terms of pure business decisions, it seems that Qatar and Australia have an advantage in East Asia and in India. However, strategic considerations require large buyers to diversify their suppliers. Hence, countries like China will consider many factors beyond price. China may want to impose tariffs on US LNG, but it would be at the cost of giving Qatar and Australia much more leverage in their dealings with Chinese buyers. In sum, the flexibility of LNG allows buyers more strategic choices at little cost differentials and the producers a larger slate of buyers.

The author would like to thank Evan Schell at Johns Hopkins School of Advanced International Studies for his research and constructive edits.

APPENDIX 1

US-BASED PLANTS UNDER CONSTRUCTION[79]			
PROJECT NAME	START DATE	NAME PLATE CAPACITY [million t/y]	OWNERS
Elba Island T1-6	2018	1.5	Kinder Morgan Inc.
Cameron T1	2019	4	Sempra Energy, Mitsubishi/NYK Line JV, Mitsui, ENGIE
Cameron T2	2019	4	Sempra, Mitsubishi/NYK Line JV, Mitsui, ENGIE
Freeport LNG T1	2019	5.1	Freeport LNG, JERA, Osaka Gas Co.
Corpus Christi LNG T1	2019	4.5	Cheniere Energy
Elba Island LNG T7-10	2019	1	Kinder Morgan
Freeport LNG T2	2019	5.1	IFM Investors
Corpus Christi LNG T2	2019	4.5	Cheniere Energy
Cameron LNG T3	2019	4	Cheniere Energy, Total [16.6%]
Sabine Pass LNG T5	2019	4.5	Cheniere Energy, Blackstone group LP
Freeport LNG T3	2019	5.1	Freeport LNG
CAPACITY UNDER CONSTRUCTION		43.5	

UNITED STATES LNG PRODUCTION AS OF JULY 2018			
Existing Plant			
Project Name	Start Date	Name Plate Capacity [million t/y]	Owners
Kenai LNG	1969	1.5	ConocoPhillips Co.
Sabine Pass T1	2016	4.5	Cheniere Energy, Blackstone
Sabine Pass T2	2016	4.5	Cheniere Energy, Blackstone
Sabine Pass T3	2017	4.5	Cheniere Energy, Blackstone
Sabine Pass T4	2017	4.5	Cheniere Energy, Blackstone
Cove Point	2017	5.25	Dominion
EXISTING CAPACITY		26.25	

Source: *2018 World LNG Report*, International Gas Union, 71-72

79 The author prepared the table using data listed in the International Gas Union *2018 World Report*, Appendix 2, p.74.

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